



## INTERNATIONAL APPLICATION PUBLISHED UNDER THE PATENT COOPERATION TREATY (PCT)

(51) International Patent Classification <sup>6</sup> : <b>E21B 37/06</b>	<b>A1</b>	(11) International Publication Number: <b>WO 99/53170</b>
		(43) International Publication Date: 21 October 1999 (21.10.99)

(21) International Application Number: PCT/US99/07852

(22) International Filing Date: 9 April 1999 (09.04.99)

(30) Priority Data:  
60/081,170 9 April 1998 (09.04.98) US

(71) Applicant: CAMCO INTERNATIONAL INC., A SCHLUMBERGER COMPANY [US/US]; P.O. Box 1590, 14910 Airline Road, Rosharon, TX 77583-1590 (US).

(72) Inventor: BHAVSAR, Rashmi, B.; 14706 Sandy Creek, Houston, TX 77070 (US).

(74) Agent: QUISENBERRY, C., Dale; Tobor, Goldstein &amp; Healey, L.L.P., Suite 2300, 1360 Post Oak Boulevard, Houston, TX 77056-3023 (US).

(81) Designated States: AL, AM, AT, AU, AZ, BA, BB, BG, BR, BY, CA, CH, CN, CU, CZ, DE, DK, EE, ES, FI, GB, GD, GE, GH, GM, HR, HU, ID, IL, IN, IS, JP, KE, KG, KP, KR, KZ, LC, LK, LR, LS, LT, LU, LV, MD, MG, MK, MN, MW, MX, NO, NZ, PL, PT, RO, RU, SD, SE, SG, SI, SK, SL, TJ, TM, TR, TT, UA, UG, UZ, VN, YU, ZW, ARIPO patent (GH, GM, KE, LS, MW, SD, SL, SZ, UG, ZW), Eurasian patent (AM, AZ, BY, KG, KZ, MD, RU, TJ, TM), European patent (AT, BE, CH, CY, DE, DK, ES, FI, FR, GB, GR, IE, IT, LU, MC, NL, PT, SE), OAPI patent (BF, BJ, CF, CG, CI, CM, GA, GN, GW, ML, MR, NE, SN, TD, TG).

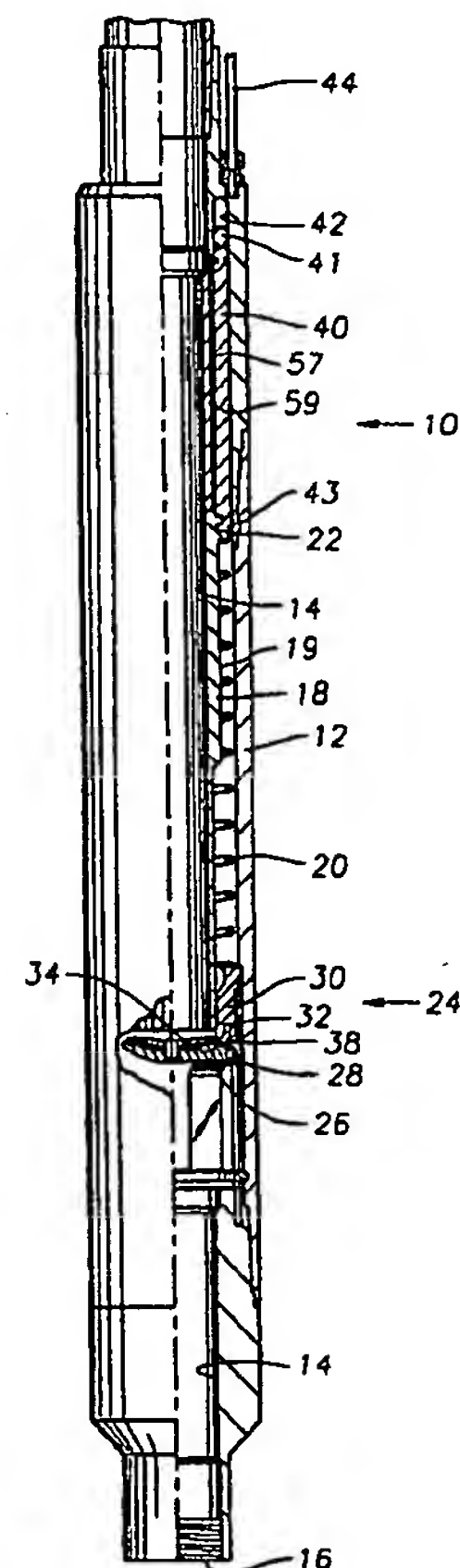
Published

With international search report.

(54) Title: COATED DOWNHOLE TOOLS

## (57) Abstract

Coated downhole tools (10, 110, 208, 310) are provided to control the flow of fluids through a well conduit, wherein a fluorinated ethylene propylene coating prevents or retards deposition of scale, solids, or other precipitates on the coated downhole tool metallic surfaces (19, 32, 68, 70, 131, 215, 230, 232, 235, 367).



**FOR THE PURPOSES OF INFORMATION ONLY**

Codes used to identify States party to the PCT on the front pages of pamphlets publishing international applications under the PCT.

AL	Albania	ES	Spain	LS	Lesotho	SI	Slovenia
AM	Armenia	FI	Finland	LT	Lithuania	SK	Slovakia
AT	Austria	FR	France	LU	Luxembourg	SN	Senegal
AU	Australia	GA	Gabon	LV	Latvia	SZ	Swaziland
AZ	Azerbaijan	GB	United Kingdom	MC	Monaco	TD	Chad
BA	Bosnia and Herzegovina	GE	Georgia	MD	Republic of Moldova	TG	Togo
BB	Barbados	GH	Ghana	MG	Madagascar	TJ	Tajikistan
BE	Belgium	GN	Guinea	MK	The former Yugoslav Republic of Macedonia	TM	Turkmenistan
BF	Burkina Faso	GR	Greece	ML	Mali	TR	Turkey
BG	Bulgaria	HU	Hungary	MN	Mongolia	TT	Trinidad and Tobago
BJ	Benin	IE	Ireland	MR	Mauritania	UA	Ukraine
BR	Brazil	IL	Israel	MW	Malawi	UG	Uganda
BY	Belarus	IS	Iceland	MX	Mexico	US	United States of America
CA	Canada	IT	Italy	NE	Niger	UZ	Uzbekistan
CF	Central African Republic	JP	Japan	NL	Netherlands	VN	Viet Nam
CG	Congo	KE	Kenya	NO	Norway	YU	Yugoslavia
CH	Switzerland	KG	Kyrgyzstan	NZ	New Zealand	ZW	Zimbabwe
CI	Côte d'Ivoire	KP	Democratic People's Republic of Korea	PL	Poland		
CM	Cameroon	KR	Republic of Korea	PT	Portugal		
CN	China	KZ	Kazakstan	RO	Romania		
CU	Cuba	LC	Saint Lucia	RU	Russian Federation		
CZ	Czech Republic	LI	Licchtenstein	SD	Sudan		
DE	Germany	LK	Sri Lanka	SE	Sweden		
DK	Denmark	LR	Liberia	SG	Singapore		
EE	Estonia						

## COATED DOWNHOLE TOOLS

### RELATED APPLICATIONS

This application claims the benefit of U. S. Provisional Application No. 60/081,170, filed April 9, 1998.

5

### BACKGROUND OF THE INVENTION

#### 1. Field Of The Invention

The present invention relates to subsurface or downhole tools used in onshore and offshore drilling and production. More specifically the present invention relates to downhole tools which are coated to reduce fouling on metallic parts by scale, solids deposition and other precipitates such as corrosion products, salts, clay, friable sands, paraffins, asphaltenes, and the like within a well bore.

#### 2. Description Of The Related Art

It is known that after an oil and gas well has been drilled it is completed by lining it with a string of casing that is cemented in place and then perforated adjacent a production zone containing hydrocarbon fluids. The hydrocarbon fluids flow through the casing perforations and into a well conduit, or production tubing, positioned within the casing. The well conduit and the casing form an annulus therebetween. Downhole tools known as packers are used to seal the annulus and force the produced fluid into the well conduit. The use of the term well conduit in the specification and claims includes, but is not limited to, off-shore well conduit, on-shore well conduit, oil well conduit, gas well conduit, water well conduit, injection well conduit, and gas lift well conduit. It is also known that a downhole tools, such as safety valves, sliding sleeves, gas lift valves and subsurface locks, may be used to provide a variety of services in the well conduit.

Subsurface safety valves are commonly used in wells to prevent uncontrolled fluid flow through the well in the event of an emergency, such as to prevent a well blowout. Conventional safety valves use a flapper which is biased by a spring to a normally closed position, but is retained in an open position by the application of hydraulic fluid from the earth's surface. The hydraulic fluid actuates a piston which, in turn, forces a flow tube downwardly which actuates the flapper. For example, when the hydraulic pressure applied to the piston exceeds the force needed to compress the spring, the piston is forced downwardly, causing the flow tube to contact and open the flapper, allowing the fluid to flow. However, when the hydraulic pressure applied is decreased, as by command from the earth's surface or by the control conduit being damaged, the spring forces the piston and the flow tube upward and away from the flapper. The flapper is then able to seat against an annular sealing surface and prevent fluid flow into the well conduit. The metallic parts of the safety valve are carefully machined and designed to facilitate smooth operation. For example, sliding components such as the piston and flowtube which vertically slide along the outside diameter of the piston protector sleeve are optimized geometrically and have carefully designed clearances. Nevertheless, scale and other deposits can come out of solution or otherwise build up on the metallic parts resulting in sticking, galling or even preventing the safety valve from closing. Operational problems, such as sticking, can also occur during the reopening of the safety valve. Production problems may result if the safety valve sticks shut following planned safety tests.

In addition, subsurface safety valves may optionally have a lock-out choke. Lock-out chokes may be used to permanently lock a subsurface safety valve in the open position. The flowtube and lock-out choke slide vertically along each other. Scale and other deposits that may come out of solution or otherwise build up on the sliding metallic surfaces may result in sticking or galling that could prevent the operation of the lock-out choke.

Another well-known downhole tool that can be selectively opened and closed, is a sliding sleeve. Sliding sleeves allow communication between the well conduit and casing annulus. Sliding sleeves may be connected in series with the tubing string to control fluid flow from the production zone to the earth's surface. Alternatively, in petroleum production, they may be used to control the flow of various fluids for stimulating or working a well from the earth's surface through the tubing string into the well annulus. Sliding sleeves are generally controlled from the earth's surface by wireline tools, or by other mechanisms known to those of ordinary skill in the art. In order for the sliding sleeve to function properly it is very important that the sliding components have a clean surface free of scale or deposits. In addition, for the sleeve to properly engage and disengage between different operating modes, it is important that the collet ribs and recesses which the ribs mate within are free of scale or deposits. As discussed herein, scale and other deposits can come out of solution or otherwise build up on the metallic parts resulting in sticking, galling or even inoperable downhole tools.

Gas lift valves are downhole tools used to increase recovery of fluids from wells with decreased hydrostatic pressure. Generally, for new producing formations, the pressure of the producing formation is greater than the hydrostatic pressure of the fluid in the wellbore, allowing the well to flow without artificial lift. However, as an oil bearing formation matures, and some significant percentage of the product is recovered, a reduction in the formation pressure occurs. With this reduction in formation pressure, the hydrocarbon issuance therefrom is likewise reduced to a point where the well no longer flows without assistance, despite the presence of significant volumes of valuable product still in place in the oil bearing stratum. In wells where this type of production decrease occurs, or if the formation pressure is low from the outset, artificial lift is commonly employed to enhance the recovery of oil from the formation.

In order for oil to be produced utilizing gas lift, a precise volume and velocity of the gas flowing upward through the tubing must be maintained. Gas injected into the hydrostatic column of fluid decreases the column's total density and pressure gradient, allowing the well to flow. As the tubing size increases, the volume of gas required to maintain the well in a flowing condition increases as the square of the increase in tubing diameter. If the volume of the gas lifting the oil is not maintained, the produced oil falls back down the tubing, and the well suffers a condition commonly known as "loading up." If the volume of gas is too great, the cost of compression and recovery of the lift gas becomes a significant percentage of the production cost. As a result, the size of a gas injection orifice in the gas lift valve is of crucial importance to the stable operation of the well.

In gas lift operations, high pressure injection gas enters the gas injection orifice or port in the valve body from the casing annulus and acts upon a bellows. When the combined force resulting from the injection gas pressure on the bellows area less the port area and the production pressure operating over the port area is greater than the force caused by the nitrogen charge within the bellows, the bellows is compressed and the valve stem tip is lifted off the valve seat, opening the valve. The injection gas flows through the seat and into the production tubing. When the pressure of the injection gas in the casing annulus at valve depth drops below the valve set pressure, the valve bellows extends downward, causing the ball of the stem tip to seat and close the valve. Reverse flow through the valve is prevented by an integral check valve in the nose of the valve body. For correct gas lift valve operation and for proper gas flow it is important that the portions of the outer surface of the valve body, the port, and the choke remain clean and free of scale or deposits that would interfere with the gas flow. It is also important that the integral check valve remain clean and free of scale or deposits that could interfere with it sealing tight against its seat. In addition to the scale and deposit problems associated with water or oil



well operations, some gas wells have high concentrations of corrosive hydrogen sulfide and/or carbon dioxide. Produced gas, including any corrosive gases present, may be used for gas lift operations. Therefore, corrosive conditions involving the hydrogen sulfide and/or carbon dioxide may result in additional fouling.

5           Many times downhole tools, known as subsurface locks, are attached to subsurface control devices such as safety valves, blanking plugs and standing valves. The subsurface lock anchors the valve or accessory in position in the tubing string. The subsurface lock and accessory are landed in an appropriate nipple by standard wireline methods. It is important that the depth of the subsurface lock placement be accurate to enable the valve or accessory to preform  
10 properly. It is also important to be able to attach a pulling tool to the subsurface lock when anchored valves or accessories need maintenance or replacement. Therefore, it is important that the fishing neck, the expander tube, the lock housing and locking dogs remain clean and free of scale or deposits that could interfere with the subsurface lock being properly placed or retrieved.

          The reasons for scale, solids and other precipitates depositing within the well conduit are  
15 many and varied. Many well environments produce scale, wax, asphaltenes and other foulants. Highly unconsolidated well formations may slough loose, friable sands into the well conduit. Clays can be remineralized and deposit on surfaces. Bacterial growth can also occur, resulting in fouled surfaces. Workover fluids or corrosive gas well conditions can produce high corrosion rates on metal surfaces, resulting in corrosion product deposition. Operational problems such  
20 as ineffective or loss of viscosifying agents added to keep solids suspended in the produced fluids may result in solids deposition. Loss of annular velocity caused by the surface pump rate capability as well as torturous fluid paths or transient pressure drops within downhole tools may result in deposition of solids.

In addition to the above factors, for petroleum wells, the temperature and pressures found in the producing zone toward the bottom of the well are higher than those at the surface. Paraffins, waxes and asphaltenes may solidify when moving up the well conduit to the surface. Factors affecting the solidification or precipitation of these components as the oil moves toward the surface in the well conduit include their concentration in the produced oil, the temperature, the absolute pressure, and the rate of pressure drop through the well conduit which partially depends on the configuration and geometry of the fluid's flowpath. The point in the well conduit where the solidification or precipitation of these components generally occurs is broadly defined herein as the "deposition zone." In addition, in-situ clays found in the fluid may remineralize and deposit on downhole equipment.

Therefore, the art has sought a method for preventing, or reducing the rate of deposition of, scale, solids or other precipitates on downhole tool metallic surfaces and a downhole tool resistant to deposition of scale, solids, or other precipitates. Viscosifiers, foams, and other solids washing programs have been used to combat scaling and solids deposition problems in the well conduit. Specially formulated fluids which inhibit remineralization or hydration of in-situ clays have also been injected into the well. Corrosion inhibitors and special metallurgies have also been used to combat deposit of corrosion products. Pipe coatings have been used to control corrosion and to reduce friction losses. Downhole tools have also been coated to improve lubricity, and friction reduction through antistick properties of the selected coatings. However, the art continues to seek methods with the ability to prevent or reduce the rate of scaling and solids deposition, and downhole tools which are resistant to deposition of scale, solids, or other precipitates.



## SUMMARY OF THE INVENTION

The present invention has been contemplated to prevent or reduce the rate of deposition of scale, solids or other precipitates on downhole tool metallic surfaces. The use of the term metallic surfaces, metallic parts or metallic portions in the specification and claims include, but is not limited to aluminum, steel, stainless steel, and nickel alloys. The downhole tool of the present invention has a plurality of metallic parts, at least one of the metallic parts having a portion of the part coated by a fluorinated ethylene propylene coating in a sufficient amount to impart anti-deposition properties to the metallic portions coated. The use of the term downhole tool in the specification and claims includes, but is not limited to, well completion tools, subsurface safety valves, gas lift valves, sliding sleeves, and subsurface locks. A feature of the present invention includes use of a fluorinated ethylene propylene coating with the ability to prevent or retard scale and solids deposition. The present invention may also include a resin primer, such as a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder to increase the ability of the anti-deposition coating to adhere to the metallic portions covered. In accordance with this aspect of the present invention, the fluorinated ethylene propylene coating may be applied over a perfluoroalkoxy copolymer resin primer to promote adhesion of the fluorinated ethylene propylene coating to the metallic part.

Another feature of the present invention is to thinly coat the metallic parts so that tool redesign is not required and so that coated replacement parts may be used with current designs. This foregoing advantage is achieved by limiting the coating thickness to a range from about 0.8 to about 2.0 mils dry film thickness. In a preferred embodiment of the present invention, the fluorinated ethylene propylene coating is applied over a perfluoroalkoxy copolymer resin containing a polyamide-imide binder such that the total coating has a thickness ranging from about 0.8 to about 2.0 dry mils.

Another feature of the present invention may include the use of a downhole tool for controlling fluid flow in a well conduit. The downhole tool with a plurality of metallic parts may be coated first with fluorinated ethylene propylene over a portion of at least one of the metallic parts of the downhole tool, the first coating having a thickness ranging from about 0.7 to about 0.9 mils dry film thickness with a topcoat or second coat of fluorinated ethylene propylene over the first coating, the second coating having a thickness ranging from about 0.2 to about 0.5 mils dry film thickness. The first coating may be of perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder.

In another specific embodiment, the metallic parts may be coated with polyphenylene sulfide (PPS) containing polytetrafluoroethylene (PTFE). In this embodiment, the thickness of the PPS and PTFE may be approximately 1.0 mil dry film thickness.

While the present invention may be used with any downhole tool, another aspect of the present invention includes well completion tools, subsurface safety valves, gas lift valves, sliding sleeves, and subsurface locks. Any metallic surface in the downhole tool may be coated as in the present invention. A further feature of the present invention for downhole tools with metallic seals includes coating at least a portion of at least one surface of the metallic seal. The coating of the metallic seal surfaces in accordance with the present invention, increases both its lubricity and its anti-deposition performance.

A further advantage of the present invention is to selectively coat surfaces that are subject to scaling and/or deposition of solids or subject to performance degradation if fouled by the scaling and/or deposition of solids. In accordance with this aspect of the present invention, at least a portion of the flow tube, the lockout-choke and the piston protector sleeve of the subsurface safety valves may be coated, each piece alone or in combination with the others. For gas lift valves, at least a portion of the plurality of outside surfaces, the fishing neck, the port in

the valve body, the integral check valve in the nose of the valve body and the choke, if present, may be coated, each surface alone or in combination with the others. For sliding sleeves, at least a portion of the inner sleeve, the collet ribs and recesses may be coated, each surface alone or in combination with the others. For subsurface locks, at least a portion of the fishing neck, the expander tube, the lock housing and locking dogs may be coated, each surface alone or in combination with the others.

The method of the present invention for controlling fluid production in a well conduit includes the steps of providing a downhole tool having a plurality of metallic parts; providing a fluorinated ethylene propylene coating over a portion of a least one of the metallic parts of the downhole tools wherein the coating is in a sufficient amount to impart anti-deposition properties to the metallic portions covered; and connecting the downhole tool to a tubing string forming a part of the well conduit. Another feature of the present invention may include the step of using a well completion tool. Still, another feature of the present invention may include the step of locating the downhole tool in a deposition zone of the well conduit. A further feature of the present invention may include the step of providing the fluorinated ethylene propylene coating over a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder. In another specific embodiment, the present invention may include the step of providing a coating of polyphenylene sulfide (PPS) containing polytetrafluoroethylene (PTFE).

### BRIEF DESCRIPTION OF THE DRAWINGS

In the Drawings:

Figure 1 is an elevational side view, partially in cross-section, showing a subsurface safety valve of the present invention;

Figure 2 is an elevational side view, partially in cross-section, showing a lock-out choke, an option on a subsurface safety valve of the present invention;

Figures 3A through 3C are partial cross-sectional elevation views which together show a sliding sleeve of the present invention in a run-in position;

Figures 4A and 4B are partial cross-sectional elevation views which together show a sliding sleeve of the present invention in an open position;

5 Figure 5 is an elevational side view, partially in cross-section, showing a gas lift valve of the present invention;

Figure 6 is an elevational side view, partially in cross-section, showing a subsurface lock of the present invention in an unlocked position; and

10 Figure 7 is an elevational side view, partially in cross-section, showing a subsurface lock of the present invention in a locked position.

While the invention will be described in connection with the preferred embodiments, it will be understood that it is not intended to limit the invention to those embodiments. On the contrary, it is intended to cover all alternatives, modifications, and equivalents as may be included within the spirit and scope of the invention as defined by the appended claims.

## 15 DETAILED DESCRIPTION OF THE INVENTION

For purposes of the following description, it should be understood that the present invention can be used in any commercially available downhole tool, whether it is tubing conveyed, wireline conveyed, hydraulically operated, or electrically operated. The figures are not necessarily drawn to scale, and in some instances, have been exaggerated or simplified to  
20 clarify certain features of the invention. For the purposes of this discussion, the terms "upper" and "lower," "up hole" and "downhole," and "upwardly" and "downwardly" are relative terms to indicate position and direction of movement in easily recognized terms. Usually, these terms are relative to a line drawn from an upmost position at the surface to a point at the center of the earth, and would be appropriate for use in relatively straight, vertical wellbores. However, when

the wellbore is highly deviated, such as from about 60 degrees from vertical, or horizontal, these terms do not make sense and therefore should not be taken as limitations. These terms are only used for ease of understanding as an indication of what the position or movement would be if taken within a vertical wellbore. One skilled in the art will appreciate many differing applications of the described apparatus.

A feature of the present invention includes use of a substantially pure fluorinated ethylene propylene coating, free of dispersion agents, with ability to prevent or retard scale and solids deposition. The fluorinated ethylene propylene coating used may be, for example Xylan® 1756, available from Whitford Corporation headquartered in West Chester, Pennsylvania. The present invention may also include a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder to increase the ability of the anti-deposition coating to adhere to the metallic portions covered. Examples of this primer, Xylan® 1220 or Xylan® 1700, are also available from Whitford Corporation. In an alternative specific embodiment, the present invention may include use of a polyphenylene sulfide (PPS) coating containing polytetrafluoroethylene (PTFE), such as Xylan® 1331H, also available from Whitford Corporation. In a specific embodiment, the PPS/PTFE coating may have an approximate dry film thickness of 1.0 mil. The present invention may include a downhole tool for controlling fluid flow in a well conduit with a plurality of metallic parts and a fluorinated ethylene propylene coating over a portion of at least one of the metallic parts of the downhole tool formed by: applying a first coat of fluorinated ethylene propylene primer, the first coat having a thickness ranging from about 0.7 to about 0.9 mils dry film thickness; baking the primed tool at 400°F for five minutes; air cooling of the tool; applying a second coat of fluorinated ethylene propylene, the second coat having a thickness ranging from about 0.2 to about 0.5 mils dry film thickness; flashing the downhole tool at 200 °F for five minutes; baking the downhole tool at 750 °F for five minutes and air cooling the downhole tool.

In yet a more preferred embodiment of the present invention, for better adhesion of the anti-deposition coating, a perfluoroalkoxy copolymer resin primer containing a polyamide-imide binder may be substituted for the first coat of fluorinated ethylene propylene primer.

It will be assumed that for subsurface safety valves, the present invention is installed within a subsurface safety valve of the type shown in U.S. Patent No. 4,161,219, which type is commonly referred to as a rod-piston safety valve. Referring to the drawings in detail, wherein like numerals denote identical elements throughout the several views, there is shown in Figure 1 a specific embodiment of a subsurface safety valve 10 constructed in accordance with the present invention. With reference to Figure 1, the subsurface safety valve 10 of this specific embodiment comprises a generally tubular body 12 with a longitudinal bore 14 that extends therethrough. Each end of the body 12 includes mechanisms, such as threads 16, for interconnection with a pipe string (not shown) suspended within a wellbore (not shown). A sleeve member 18, usually referred to as a flow tube, is disposed within the bore 14 and is adapted for axial movement therein. The flow tube 18 has an outer surface 19 which is subject to fouling by scaling or solids deposition. The flow tube 18 includes a spring 20 disposed therearound that acts upon a shoulder 22 on the flow tube 18 biasing the flow tube 18 away from a flapper mechanism 24.

Still with reference to Figure 1, the flapper mechanism 24 generally comprises a disc or flapper valve closure member 26 with an arm 28 on a peripheral edge thereof that is hingedly connected to an annular housing 30 mounted within the bore 14. In a specific embodiment, the annular housing 30 includes a metallic annular sealing surface 32 cooperable with an annular sealing surface 34 on the flapper 26. In a specific embodiment, the annular housing 30 may further include a secondary annular sealing surface 38 formed from an annular body of pliable



material, which is cooperable with the annular sealing surface 34 on the flapper 26. The metallic sealing surface 32 is generally referred to as the "hard seat" and the pliable sealing surface 38 is generally referred to as the "soft seat."

As shown in Figure 1, in a specific embodiment, a rod-piston system may be provided to open the flapper 26, and may be comprised of a piston 40 sealably mounted for reciprocal movement within a cylinder 42 located within the wall of the tubular body 12. A first end 41 of the piston 40 is in contact with hydraulic fluid (not shown) provided thereto from the earth's surface through a relatively small diameter control conduit 44. A second end 43 of the piston 40 is operatively connected, in any suitable manner, to the flow tube 18. When the pressure of hydraulic fluid in the control conduit 44 exceeds the force needed to compress the spring 20, the piston 40 is forced downwardly, thereby causing the flow tube 18 to come into contact with, and open, the flapper 26. The piston 40 is guided by a piston protector sleeve 59 as it moves axially. The outer surface 57 of the piston protector sleeve 59 is a surface subject to fouling by scaling or solids deposition. In the event that the hydraulic pressure applied to the piston 40 is decreased, as by command from the earth's surface or by the control conduit 44 being damaged, the spring 20 forces the flow tube 18 upwardly away from the flapper 26. The flapper 26 is then rotated, and biased, into a closed position by action of a hinge spring (not shown) to permit the annular sealing surfaces 32, 34 and 38 to mate and thereby establish a fluid seal to prevent fluid flow into the flow tube 18. A fluorinated ethylene propylene coating on the outer surface 19 of the flow tube 18 or the outer surface 57 of the piston protection sleeve 59 may eliminate or retard fouling with scale or deposited solids that could prevent the flapper 26 from actuating properly and prevent valve failure.

In reference to Figure 2, in the life of a well it may be necessary to permanently lock a valve open. An option, known as a lock-out choke 55, may be added to a subsurface safety valve to preform this function. In a specific embodiment, a choke sleeve member 56 is disposed within the inside diameter of a flow tube 18 and connected thereto by shear pins 60. When it is desired to open a subsurface safety valve, the pressure of the hydraulic fluid in the control conduit (not shown) is increased until it exceeds the force needed to compress the spring 20, whereby the piston 40 is forced downwardly. The downward motion of the piston 40 causes the flow tube 18 to force the choke sleeve member 56 downwardly into contact with, and open, the flapper 26. When it is desired to permanently lock open the subsurface safety valve, a wire line shifting tool (not shown) is engaged with a profile 61 on the inner surface of the choke sleeve member 56 and used to mechanically apply downward forces to the choke sleeve member 56. The downward jarring of the wireline tool (not shown) will shear each of the shear pins 60, thereby separating the choke sleeve member 56 from the flow tube 18 and allowing the choke sleeve member 56 to travel downwardly towards the flapper 26. This allows a snap ring 66 disposed about the choke sleeve member 56 to expand radially into engagement with a shoulder 62 formed in the annular housing 30, thereby preventing upward movement of the choke sleeve member 56 and permanently locking the choke sleeve member 56 and flapper 26 in open positions. Scaling and/or solids deposition on the axially sliding surfaces of the choke sleeve member 56 and the flow tube 18 can prevent operation of the lock-out choke. A fluorinated ethylene propylene coating on the outer surface 68 of the choke sleeve member 56 and on the inner surface 70 of the flow tube 18 may prevent scaling and solids deposition that could interfere with the operation of the lockout choke 55.

Figures 3A-3C illustrate the sliding sleeve 110 in its initial or run-in configuration. Referring to Figure 3A, in a specific embodiment, the sliding sleeve 110 of the present invention includes a housing 118 having a longitudinal bore 120 extending therethrough. An inner sleeve 122 is disposed for axial movement within the longitudinal bore 120. A piston 124 is associated with the inner sleeve 122 and the longitudinal bore 120. In a specific embodiment, the piston 124 may be sealably disposed around the inner sleeve 122 and within the longitudinal bore 120 of the housing 118. The piston 124 is provided with an upper surface 124a, a lower surface 124b, an inner annular piston seal 124c, an outer upper annular piston seal 124d, and an outer lower annular piston seal 124e. The inner annular piston seal 124c is disposed between the inner sleeve 122 and the piston 124. The outer annular piston seals 124d and 124e are disposed between the piston 124 and the housing 118. At least one annulus pressure port 126 is provided through the housing 118 for exposing the piston 124 to pressure within an annulus (not shown) between the tubular conduit (not shown) and the casing (not shown). During the run-in mode, as shown in Figure 3A, and before the sliding sleeve is first actuated: the piston 124 is releasably secured to the housing 118, for example, by at least one shear pin 125; the upper surface 124a of the piston 124 is abutted against an upper shoulder 127 of the inner sleeve 122; the lower surface 124b of the piston is displaced above an annular shoulder 129 within the longitudinal bore 120 of the housing 118; and the outer annular seals 124d and 124e are located above the at least one annulus pressure port 126. The housing may also be provided with an annular housing seal 133 beneath the at least one shear pin 125 and above the annular shoulder 129. The function of the housing seal 133 will be explained below.

Referring now to Figure 3B, the housing 118 is provided with at least one outer fluid flow port 130, and the inner sleeve 122 is provided with at least one inner fluid flow port 132. An

upper annular flow port seal 134 is disposed above the at least one outer fluid flow port 130 and between the housing 118 and the inner sleeve 122. Similarly, a lower annular flow port seal 136 is disposed below the at least one outer fluid flow port 130 and between the housing 118 and the inner sleeve 122. A coating of fluorinated ethylene propylene on at least a portion of the outer surface 131 of the inner sleeve 122 may prevent or retard scaling and solids deposition that could interfere with the operation of the sliding sleeve 110. In particular, a coating between the upper annular flow port seal 134 and the lower annular flow port seal 136, where the inner sleeve 122 outer surface 131 is subject to scale and solids deposition could beneficially prevent or retard scaling and/or solids deposition. In a specific embodiment, the flow port seals 134 and 136 may be chevron packing, as well known to those of skill in the art. As will be more fully explained below, the at least one outer fluid flow port 130 and the at least one inner fluid flow port 132 sealably cooperate to control fluid flow between the annulus (not shown) and a longitudinal bore 123 through the inner sleeve 122. Figure 3B illustrates the fluid flow ports 130 and 132 in a closed or non-aligned relationship. In this position, fluid flow from the annulus (not shown) is prevented from flowing into the longitudinal bore 123 of the inner sleeve 122. Further, the upper and lower annular seals 134 and 136 prevent fluid from migrating upwardly or downwardly in the annular space between the housing 118 and the inner sleeve 122. The inner sleeve 122 may also be provided with at least one equalizing port 135 above the at least one flow port 132. The function of the at least one equalizing port 135 will be explained below.

As shown in Figure 3C, the lower end of the inner sleeve 122 is provided with a collet 138 having an annular rib, or collet, 140. The longitudinal bore 120 through the housing 118 is provided with a number of annular recesses for receiving the collet rib 140. In a specific embodiment, the bore 120 may be provided with an upper annular recess 142 (Figure 3B), an

intermediate annular recess 144, and a lower annular recess 146. In another embodiment, the bore 120 may also be provided with an equalizing recess 143 between the upper recess 142 and the intermediate recess 144. The collet rib 140 is located in the intermediate recess 144 when the sliding sleeve 110 is in its run-in mode, as shown in Figures 3A-3C. The relationship  
5 between the collet rib 140 and the upper, equalizing, and lower recesses 142, 143, and 146 will be described below. A fluorinated ethylene propylene coating on at least a portion, or preferably the entire surface, of the collet rib 140 and mating annular recesses 142-144, 146, may prevent scaling and solids deposition that could interfere with the operation of the sliding sleeve 110.

When it is desired to move the sliding sleeve 110 to its open position, as shown in Figure  
10 4A-  
4B, to establish fluid communication through the fluid flow ports 130 and 132, pressure is applied to the annulus (not shown), in any manner known to those of skill in the art. Referring to Figure 3A, the annulus pressure is applied to the piston 124 through the at least one annulus pressure port 126. The annulus pressure is contained by the inner piston seal 124c, the outer  
15 lower piston seal 124e, and the upper annular fluid flow port seal 134, and acts upon the lower piston surface 124b to force the piston 124 and the inner sleeve 122 upwardly. The force applied to the lower piston surface 124b by the annulus pressure should be sufficient to (a) release the piston from the housing, for example, by shearing the at least one shear pin 125, and (b) disengage the collet rib 140 from the intermediate recess 144 (not shown). Referring to Figure  
20 4A, the piston 124 and inner sleeve 122 cease upward movement when an upper surface 148 of the inner sleeve 122 abuts against an upper annular shoulder 150 within the longitudinal bore 120 of the housing 118. When the inner sleeve 122 is in this uppermost position, the sliding sleeve 110 of the present invention is in its open position. As shown in Figure 4B, opening the sliding

sleeve 110 brings the flow ports 130 and 132 into alignment and establishes fluid communication between the annulus (not shown) and the longitudinal bore 123 of the inner sleeve 122. Fluids from the production zone (not shown) may then be produced to the earth's surface through the tubular conduit (not shown). The collet rib 140 is located in the upper recess 142 when the sliding sleeve 110 is in its open position.

If it is desired to equalize the pressure between the annulus (not shown) and the longitudinal bore 123 of the inner sleeve 122 — so as to avoid an initial rapid fluid flow through the flow ports 130 and 132 — the collet rib 140 may be moved into, and held in, the equalizing recess 143 prior to being moved into the upper recess 142. This will move the inner sleeve 122 up to a point so that fluid communication is established from the at least one outer flow port 130 through the at least one equalizing port 135 but is not established through the at least one inner flow port 132. After the pressure between the annulus (not shown) and the longitudinal bore 123 of the inner sleeve 122 is equalized through the at least one equalizing port 135, the inner sleeve 122 may then be moved upwardly until flow ports 130 and 132 are aligned, as more fully explained above.

When it is desired to move the sliding sleeve 110 to its closed position, as shown in Figures 3A-3C, to stop the flow of fluids from the production zone (not shown), a wireline shifting tool (not shown) is used to apply a downward impact force to the inner sleeve 122, in a manner well known to those ordinarily skilled in the art. Fluid communication through the ports 130 and 132 will be fully terminated when the at least one flow port 132 in the inner sleeve 122 is moved below the lower flow port seal 136. The sliding sleeve 110 will be fully closed, and the inner sleeve 122 will be in its lowermost position, when the collet rib 140 is located in the lower recess 146 (not shown). There is shown in Figure 5 a specific embodiment of a gas



lift valve 208 in the closed position constructed in accordance with the present invention. With reference to Figure 5, the gas lift valve 208 of this specific embodiment comprises a generally tubular body 210 with a longitudinal bore 212 for sealable insertion in a side pocket mandrel (not shown). A bellows 218 located within the wall of the gas lift valve body 210 biases a valve stem 220 and ball 216 downwardly against the ball valve seat 222 into a closed position. The bellows 218 may be preset in any manner known to those of skill in the art before insertion into the side pocket mandrel (not shown) to the desired flowing pressure at the valve depth in the well conduit. When the combined force resulting from the injection gas pressure on the bellows area 218 less the injection gas pressure on the area of the ball 217 above the seat 222 and the production pressure operating over the area of the ball 219 below the seat 222 is greater than the force present within the bellows 218, the bellows 218 is compressed. The bellows 218 lifts the valve stem 220 and ball 216 off the ball valve seat 222, opening the valve 208 and allowing injection gas (not shown) to enter into the port 214 through the seat 222 and into the well conduit (not shown).

When the pressure of the injection gas in the casing annulus at the valve depth drops below the bellows set pressure, the bellows 218 expands causing the valve stem 220 and ball 216 to move downwardly, causing the ball 216 to seat in the ball valve seat 222. Reverse flow through the valve body 210 is prevented by an integral check valve 224 located in the nose 226 of the valve body 210. It is important that the check valve 224 remain free of any scale or deposits that could prevent it from sealing properly. Therefore, a fluorinated ethylene propylene coating on at least a portion, or preferably the entire surface of the integral check valve 224 may be useful in preventing or retarding scaling or solids deposition.

Optionally, the gas lift valve body 210 may house a choke 228 to control the maximum rate of gas through the gas lift valve 208. The optional choke 228 may be housed in the nose 226 of the gas lift valve 208 as shown in Figure 5, or alternatively, it may be located within the port 214. Control of the quantities of injection gas (not shown) is required to balance the need to  
5 lighten the fluid column and allow the natural reservoir pressure to push the fluid up the well conduit and the operational costs associated with use of excessive quantities of injection gas. Careful sizing of the port 214 diameter in combination with use of a choke 228 or variable orifice facilitates this balance. Therefore, it is important to keep the gas flow path clean and free from scale or deposits in the areas designed to restrict and control the gas quantities. A fluorinated  
10 ethylene propylene coating on the interior annular port surface 215 and on the interior surface 230 of choke 228 may prevent scaling and solids deposition that could interfere with the control of the injection gas quantities. The gas lift valve body 210 may optionally include a fishing neck 234 for adapting the gas lift valve 208 to be remotely deployed and retrieved by standard methods known to those of skill in the art. It is important that the outer surface 235 of fishing neck 234  
15 remain clean and free of scale or deposits that could interfere with the gas lift valve being properly retrieved. In addition, for gas lift valves inserted into side pocket mandrels (not shown), it is important that the portion of the outer surface contacting the mandrel, preferably the entire outer surface 232 of the gas lift valve body 210 to remain clear and free of scale or deposits to facilitate removal from the side pocket mandrels (not shown).

20 Referring now to Fig. 6, a well locking device of the present invention is shown in a running mode, being lowered into a desired downhole position within the bore 334 of tubing 330 provided within a well. Running tool 320 is shown, having a shearable shear pin 342 or other retaining means 342 connecting the running tool to the housing 344 of the well lock 340. Use

of a shearable shear pin 342 initially permits the well lock 340 to be lowered into the well bore 334 by lowering the running tool 320 attached thereto. The well lock 340 is lowered into the bore 334 of the tubing 330 until no-go shoulder 325 of the well locking device 310 abuts nipple landing shoulder 335 of the tubing 330 in a desired downhole portion 310 of tubing 330. The

5 no-go shoulder 325 and nipple landing shoulder 335 provided in connection with the well locking device 310 and tubing 330, respectively, comprise bearing means, which prevent downhole movement of the well lock 340 when the well lock 340 has reached the proper location within tubing 330 for engagement thereof. However, it should be readily apparent to one of ordinary skill in the art that the no-go shoulder 325 and nipple landing shoulder 335 can be placed in

10 various locations in connection with the well locking device 310 and the tubing 330 and other bearing means could be used. For example, a particular embodiment of the well locking device 310 of the present invention could incorporate a selective lock (not shown) having matching keys and recesses provided in connection therewith for proper placement of the well lock 340 within the tubing 330. Other bearing means will also be readily recognized by those of ordinary

15 skill in the art. In particular embodiments, such bearing means could be used in connection with certain aspects of the device and method of the present invention. Placement of the no-go shoulder 325 on the running tool 320 and not on the well lock housing 344 may increase the structural integrity of the well lock housing 344 and may eliminate the need for shearable or retractable no-go shoulders (not shown) on the well lock housing 344, which may be provided

20 in a particular embodiment to eliminate undesirable stresses on the well lock housing 344.

After the well lock 340 is positioned within the desired downhole portion of the tubing 330, and the well lock 340 is set, as described further hereinafter, an upward force may be applied to the running tool 320 to shear the shear pin 302, thus separating the running tool 320

from the well lock housing 344 and allowing the running tool 320 to be removed from the bore 335 of the tubing 330 after locking the well lock 340 in place. Shear pin 302 may be used to temporarily connect the running tool 320 to the well lock housing 344. However, other retaining means may be provided, such as retractable fingers (not shown) provided in connection with the running tool 320, to engage an inner groove such as recess 346 formed within expander tube 343 of the well lock 340. In such an embodiment, when the running tool 320 is removed from the well lock 340, the retractable fingers (not shown) may be retracted, thus disengaging the running tool 320 from the well lock 340 and permitting removal of the running tool 320 from the bore 335 of the tubing 330.

At least a portion 328 of the setting portion 326, or setting tool 326, of the running tool 320 is provided in contact with at least a portion 348 of expander tube 343 of the well lock 340. After the well lock 340 is positioned within the desired downhole portion of the tubing 330, a downward pressure force may be applied to the setting portion 326, or setting tool 326, of running tool 320, which may be resisted by abutment of the no-go shoulder 325 and nipple landing shoulder 335, provided on the running tool 320 and the tubing 330, respectively. The downward motion of setting portion 326, or setting tool 320, causes expander tube 343 of the well lock 340 to move downward within the well lock 340. As shown in Fig. 6, the well locking device 310 is initially located within the tubing 330 in a running mode, in which the locking dogs 345 of the well lock 340 are permitted to remain within the well lock 340 for lowering of the well lock 340 within the tubing 330. The well lock 340 is maintained in the running mode by use of a shear ring 350 of the present invention, which is described in detail hereinafter.

In the running mode shown in Fig. 6, at least a portion of shear ring 350 is disposed in a recess 347 formed or otherwise provided in a lower portion of expander tube 343 and at least

a portion of shear ring 350 is disposed within a corresponding upper recess 341 formed or otherwise provided in an upper portion of well lock housing 344. When setting portion 326, or setting tool 326, of running tool 320 is forced downward, the shear ring 350 is sheared along a first shear plane 356, as described hereinafter, thus permitting expander tube 343 to travel  
5 downward within the well lock housing 344 from a first, running, position, thus forcing locking dogs 345 outward from within well lock housing 344 to engage the locking dogs 345 within recess 332 formed or otherwise provided in the tubing 330.

With reference now to Fig. 7, a continued downward force applied to expander tube 343 by setting portion 326, or setting tool 326, of running tool 320 may be applied to lower expander  
10 tube 343 to a second, locking, position, whereby outwardly biased shear ring 350, as described further hereinafter, expands so that at least a portion of shear ring 350 remains disposed within the recess 347 formed or otherwise provided in expander tube 343 and at least a portion of shear ring 350 is disposed within a corresponding lower recess 342 formed or otherwise provided in a lower portion of well lock housing 344 of well lock 340, thereby fully engaging locking dogs  
15 345 within recess 332 of tubing 330 and locking the expander tube 343 in the second, locking position. Such locking of expander tube 343 in the locking position enables the well lock 340 to operate in its second, or locking mode, thereby locking the well lock 340 and any device affixed thereto (not shown) securely within the bore 334 of tubing 330.

After setting the well lock 340 of the present invention in its locking mode within the  
20 bore 334 of tubing 330, the running tool 320 and its associated setting portion 326, or setting tool 326, may be detached from the well lock 340 and removed from the bore 334 of tubing 330, leaving the well lock 340 securely locked within the bore 334 of tubing 330. In an embodiment wherein running tool 320 and well lock housing 344 are connected to one another by shear pin



302, the running tool 320 may be detached from the well lock 340 by providing an upward force on the running tool 320 sufficient to shear the shear pin 302 and thereby separate running tool 320 from well lock 340. The upward force is resisted by the locking dogs 345 engaged within the recess 332 formed or otherwise provided in the tubing 330. Thereafter, running tool 320 may be easily removed from the downhole portion of the tubing 330, leaving the well lock 340 locked in place within tubing 330.

When it is desired to remove the well lock 340 from within the bore 334 of tubing 330, a running removal tool, or pulling tool (not shown), may be provided having fingers adapted to engage the inner recess 346 formed in expander tube 343 of well lock 340. The running removal tool (not shown) may be lowered into the downhole portion of the well tubing bore 330 until it engages the expander tube 343. Thereafter, an upward force may be provided against the running removal tool (not shown) that is sufficient to shear the portion of the shear ring 350 engaged within the lower recess 342 of well lock housing 344. A continued upward force may thereafter be provided against the running removal tool (not shown) to raise the expander tube 343 from the second, locking, position within the well lock housing 344, returning the expander tube 343 to the first, running, position within well lock housing 344, which will permit locking dog 345 to be disengaged from the tubing recess 332 and permit the well lock 340 to be removed from the bore 334 of tubing 330. When the expander tube 343 is returned to the first, running, position within well lock housing 344, the well lock 340 is operable in its third, or pulling, mode. A continued upward force applied to the running removal tool (not shown) causes the expander tube 343 to abut a flange 315 formed as part of the fishing neck 365, located on other portion provided on the well lock housing 344 so that continued upward movement of the expander tube 343 will allow the well lock 340 to be removed from the downhole portion of the tubing bore



334. To eliminate or retard fouling with scale or deposited solids that could prevent the lock 340 from anchoring the valve or accessory in the proper position in the well conduit or that could prevent the lock 340 from being retrieved, a coating of fluorinated ethylene propylene is applied on a portion, or preferably the entire outer surface 367, of the fishing neck 365, expander tube 343, well lock housing 344 and locking dogs 345.

Whereas the present invention has been described in particular relation to the drawings attached hereto, it should be understood that other and further modifications, apart from those shown or suggested herein, may be made within the scope and spirit of the present invention. For example, any downhole tool that needs to be resistant to deposit of scale, solids or other precipitates may be coated, for example a landing nipple. In addition, the coating of the present invention is so thin that metallic replacement parts may be coated and inserted into current downhole tool designs as desired to retard or prevent scale and solids deposition. Accordingly, the invention is therefore to be limited only by the scope of the appended claims.

## CLAIMS

- 1           1.     A downhole tool for controlling fluid flow in a well conduit, comprising:  
2                     a plurality of metallic parts; and  
3                     a fluorinated ethylene propylene coating over a portion of at least one of  
4                     the metallic parts of the downhole tool, wherein the coating is in  
5                     a sufficient amount to impart anti-deposition properties to the  
6                     metallic portions coated.
- 1           2.     The downhole tool of claim 1, including a perfluoroalkoxy copolymer resin primer  
2     containing a polyamide-imide binder, over which the fluorinated ethylene propylene coating is  
3     applied.
- 1           3.     The downhole tool of claim 2, wherein the primer and coating have a combined  
2     thickness ranging from about 0.8 to about 2.0 mils dry film thickness.
- 1           4.     A downhole tool of claim 1, wherein the coating has a thickness ranging from  
2     about 0.8 to about 2.0 mils dry film thickness.
- 1           5.     The downhole tool of claim 1, wherein the downhole tool is a well completion  
2     tool.
- 1           6.     The downhole tool of claim 1, wherein the downhole tool is a subsurface safety  
2     valve.

1           7.       The downhole tool of claim 6, wherein the plurality of metallic parts include a  
2 flow tube, a lockout-choke and a piston protector sleeve.

1           8.       The downhole tool of claim 7, wherein at least a portion of the flow tube is coated  
2 with the fluorinated ethylene propylene coating.

1           9.       The downhole tool of claim 7, wherein at least a portion of the lockout-choke is  
2 coated with the fluorinated ethylene propylene coating.

1           10.      The downhole tool of claim 7, wherein at least a portion of the piston protector  
2 sleeve is coated with the fluorinated ethylene propylene coating.

1           11.      The downhole tool of claim 1, wherein the downhole tool is a gas lift valve.

1           12.      The downhole tool of claim 11, wherein the plurality of metallic parts include a  
2 valve body with a plurality of outer surfaces, a fishing neck, a choke, a port disposed in the valve  
3 body, and a nose, the nose having an integral check valve disposed in the nose of the valve body.

1           13.      The downhole tool of claim 12, wherein at least a portion of the outer surfaces of  
2 the valve body are coated with the fluorinated ethylene propylene coating.

1           14.      The downhole tool of claim 12, wherein at least a portion of the fishing neck is  
2 coated with the fluorinated ethylene propylene coating.

1           15.      The downhole tool of claim 12, wherein at least a portion of the port disposed in  
2 the valve body is coated with the fluorinated ethylene propylene coating.

1           16.    The downhole tool of claim 12, wherein at least a portion of the choke is coated  
2   with the fluorinated ethylene propylene coating.

1           17.    The downhole tool of claim 12, wherein at least a portion of the integral check  
2   valve disposed in the nose of the gas lift valve is coated with the fluorinated ethylene propylene  
3   coating.

1           18.    The downhole tool of claim 1, wherein the downhole tool is a sliding sleeve.

1           19.    The downhole tool of claim 18, wherein the plurality of metallic parts include an  
2   inner sleeve, having an outer surface, a plurality of collet ribs, and a housing having a  
3   longitudinal bore, wherein a plurality of recesses are disposed in the longitudinal bore.

1           20.    The downhole tool of claim 19, wherein a least a portion of the outer surface of  
2   the inner sleeve is coated with the fluorinated ethylene propylene coating.

1           21.    The downhole tool of claim 19, wherein a least one of the collet ribs is coated  
2   with the fluorinated ethylene propylene coating.

1           22.    The downhole tool of claim 19, wherein a least a one of the recesses disposed in  
2   the longitudinal bore of the housing is coated with the fluorinated ethylene propylene coating.

1           23.    The downhole tool of claim 1, wherein the downhole tool is a subsurface lock.

1           **24.**     The downhole tool of claim 23, wherein the plurality of metallic parts include a  
2     fishing neck, an expander tube, a lock housing, and a plurality of locking dogs.

1           **25.**     The downhole tool of claim 24, wherein at least a portion of the fishing neck is  
2     coated with the fluorinated ethylene propylene coating.

1           **26.**     The downhole tool of claim 24, wherein at least a portion of the expander tube is  
2     coated with the fluorinated ethylene propylene coating.

1           **27.**     The downhole tool of claim 24, wherein at least a portion of the lock housing is  
2     coated with the fluorinated ethylene propylene coating.

1           **28.**     The downhole tool of claim 24, wherein at least portion of one of the locking dogs  
2     is coated with the fluorinated ethylene propylene coating.

1           **29.**     The downhole tool of claim 1, wherein the plurality of metallic parts include at  
2     least one metallic seal having at least one surface coated with the fluorinated ethylene propylene  
3     coating.

1           **30.**     The downhole tool of claim 1, wherein the metallic parts coated with the  
2     fluorinated ethylene propylene coating have surfaces subject to scale or deposits.

1           **31.**     The downhole tool of claim 1, wherein the metallic parts coated with the  
2     fluorinated ethylene propylene have surfaces subject to performance degradation by scale or  
3     deposits.

1           **32.**    A downhole tool for controlling fluid flow in a well conduit, comprising:  
2                           a plurality of metallic parts; and  
3                           a polyphenylene sulfide coating containing polytetrafluoroethylene over  
4                           a portion of at least one of the metallic parts of the downhole tool,  
5                           wherein the coating is in a sufficient amount to impart anti-  
6                           deposition properties to the metallic portions coated.

1           **33.**    The downhole tool of claim 32, wherein the polyphenylene sulfide coating  
2    containing polytetrafluoroethylene has a thickness of approximately 1.0 mil dry film thickness.

1           **34.**    A method of controlling fluid production in a well conduit, comprising the steps  
2    of:  
3           (a)    providing a downhole tool having a plurality of metallic parts;  
4           (b)    providing a fluorinated ethylene propylene coating over a portion of at least one  
5                   of the metallic parts of the downhole tool wherein the coating is in a sufficient  
6                   amount to impart anti-deposition properties to the metallic portion covered; and  
7           (c)    connecting the downhole tool to a tubing string forming a part of the well  
8                   conduit.

1           **35.**    The method of claim 34, wherein the downhole tool is a well completion tool.

1           **36.**    The method of claim 34, including the step of locating the downhole tool in a  
2    deposition zone of the well conduit.

3           **37.**    The method of claim 34, including the step of providing the fluorinated ethylene  
4    propylene coating over a perfluoroalkoxy copolymer resin primer containing a polyamide-imide  
5    binder.



- 1           **38.**    A method of controlling fluid production in a well conduit, comprising the steps  
2    of:
- 3           (a)    providing a downhole tool having a plurality of metallic parts;  
4           (b)    providing a polyphenylene sulfide coating containing polytetrafluoroethylene over  
5                   a portion of at least one of the metallic parts of the downhole tool wherein the  
6                   coating is in a sufficient amount to impart anti-deposition properties to the  
7                   metallic portion covered; and  
8           (c)    connecting the downhole tool to a tubing string forming a part of the well  
9                   conduit.

- 1           **39.**    The method of claim 38, further including the step of providing the polyphenylene  
2    sulfide coating containing polytetrafluoroethylene in an approximate dry film thickness of 1.0  
3    mil.

- 1           **40.**    A downhole tool for controlling fluid flow in a well conduit, comprising:  
2                   a plurality of metallic parts;  
3                   a first coating of fluorinated ethylene propylene over a portion of at least  
4                   one of the metallic parts of the downhole tool, the first coating  
5                   having a thickness ranging from about 0.7 to about 0.9 mils dry  
6                   film thickness; and  
7                   a second coating of fluorinated ethylene propylene over the first coating,  
8                   the second coating having a thickness ranging from about 0.2 to  
9                   about 0.5 mils dry film thickness.

- 1           41.    The downhole tool of claim 40, wherein the first coating is of perfluoroalkoxy  
2 copolymer resin primer containing a polyamide-imide binder.

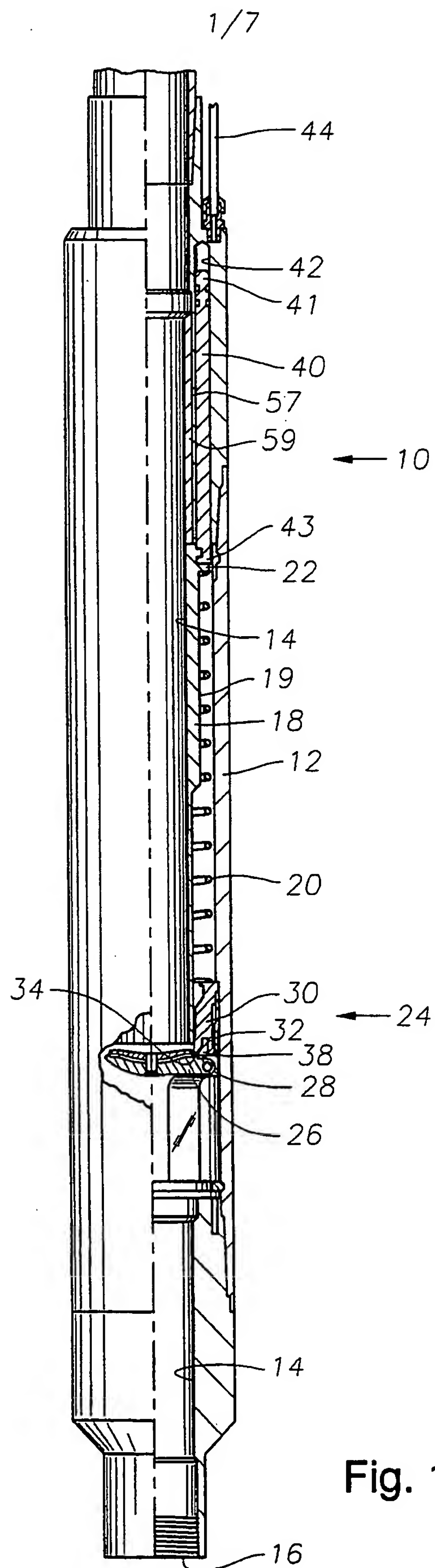


Fig. 1

2/7

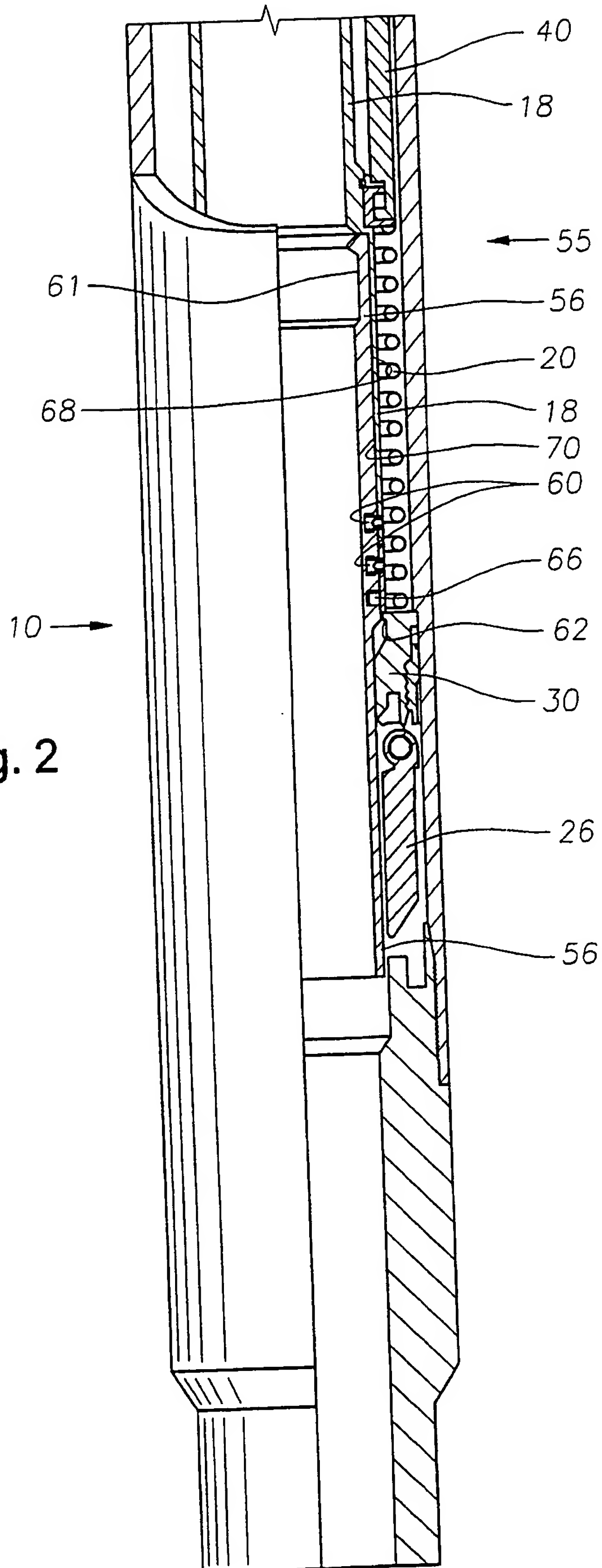


Fig. 2

3/7

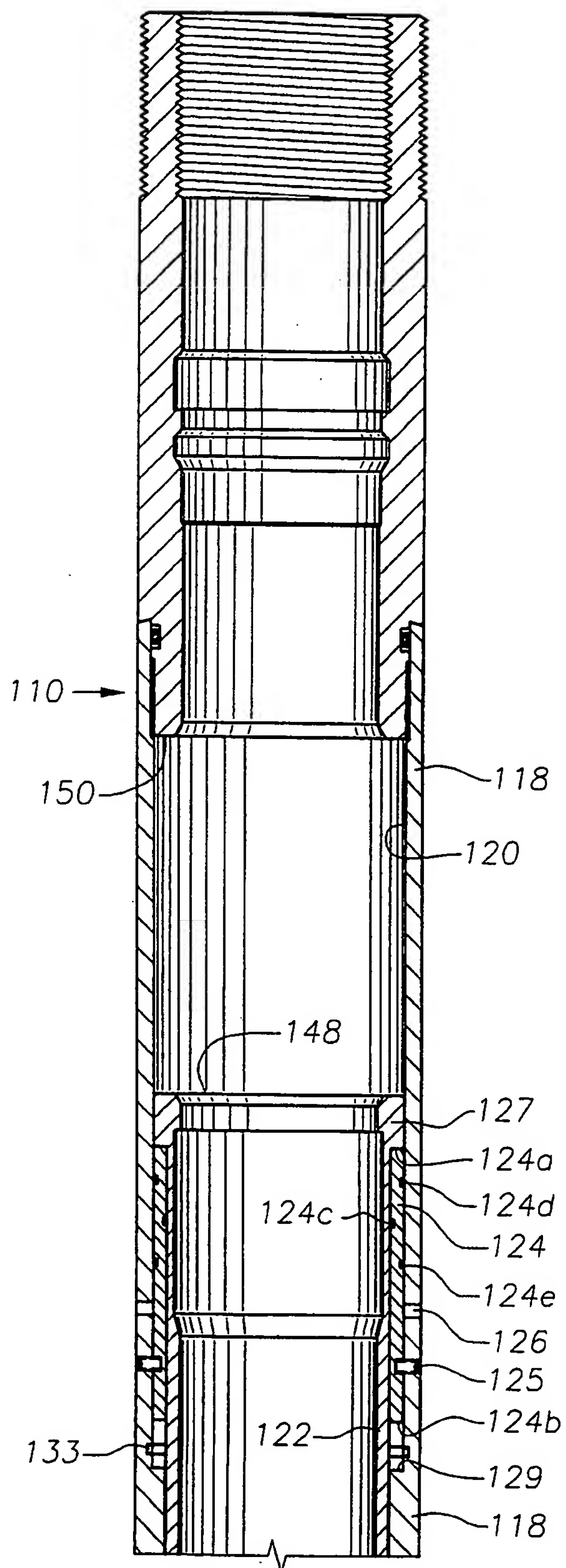


Fig. 3A

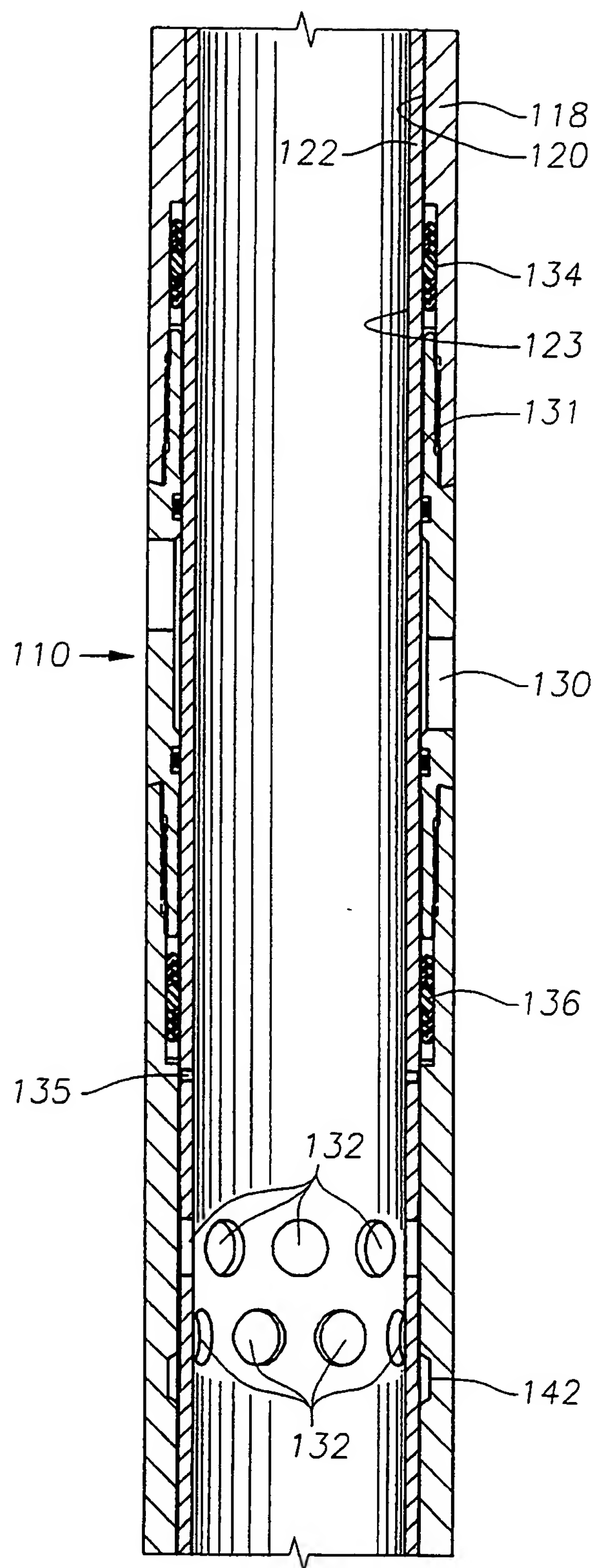


Fig. 3B

4/7

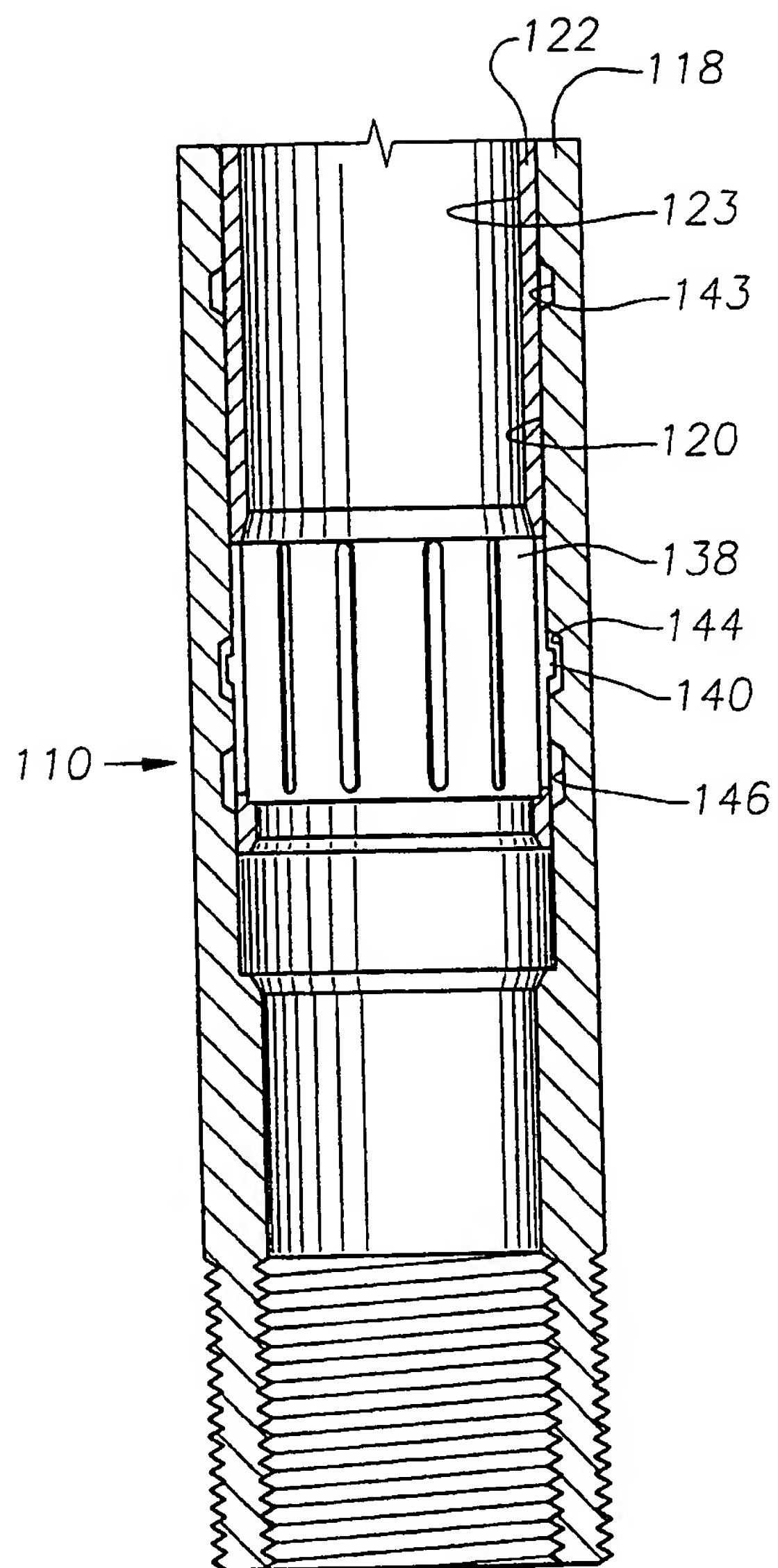


Fig. 3C

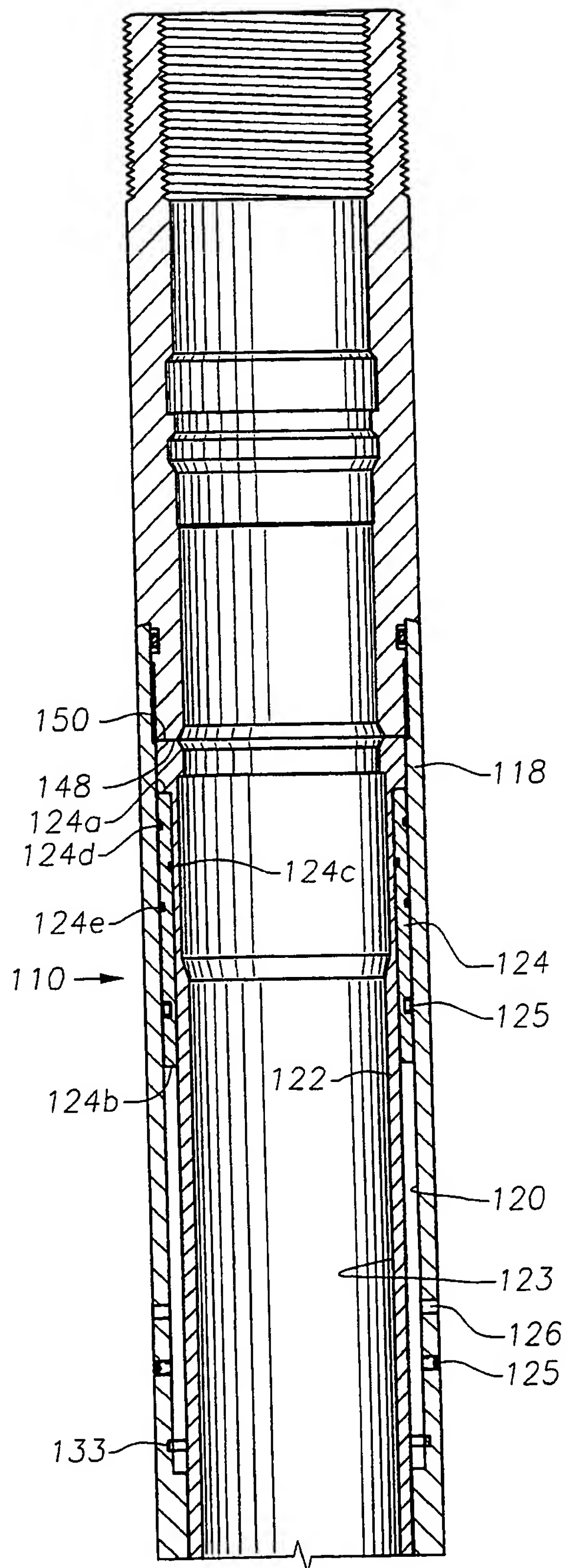


Fig. 4A



5/7

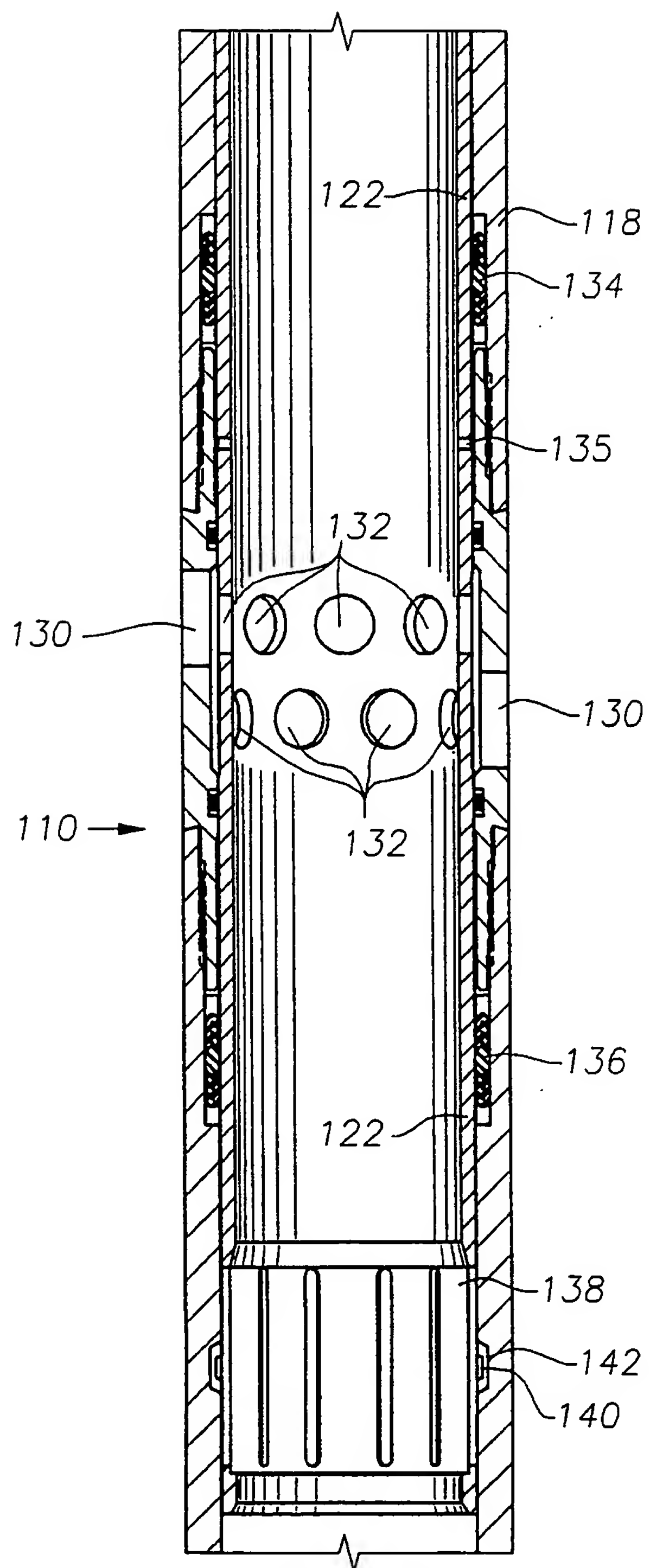


Fig. 4B

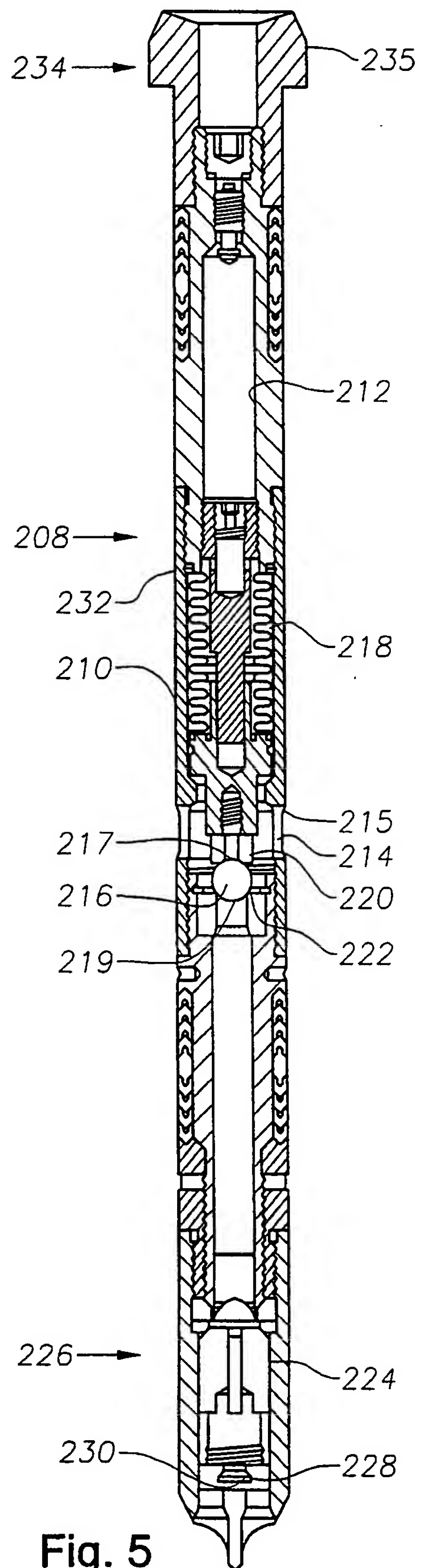


Fig. 5

6/7

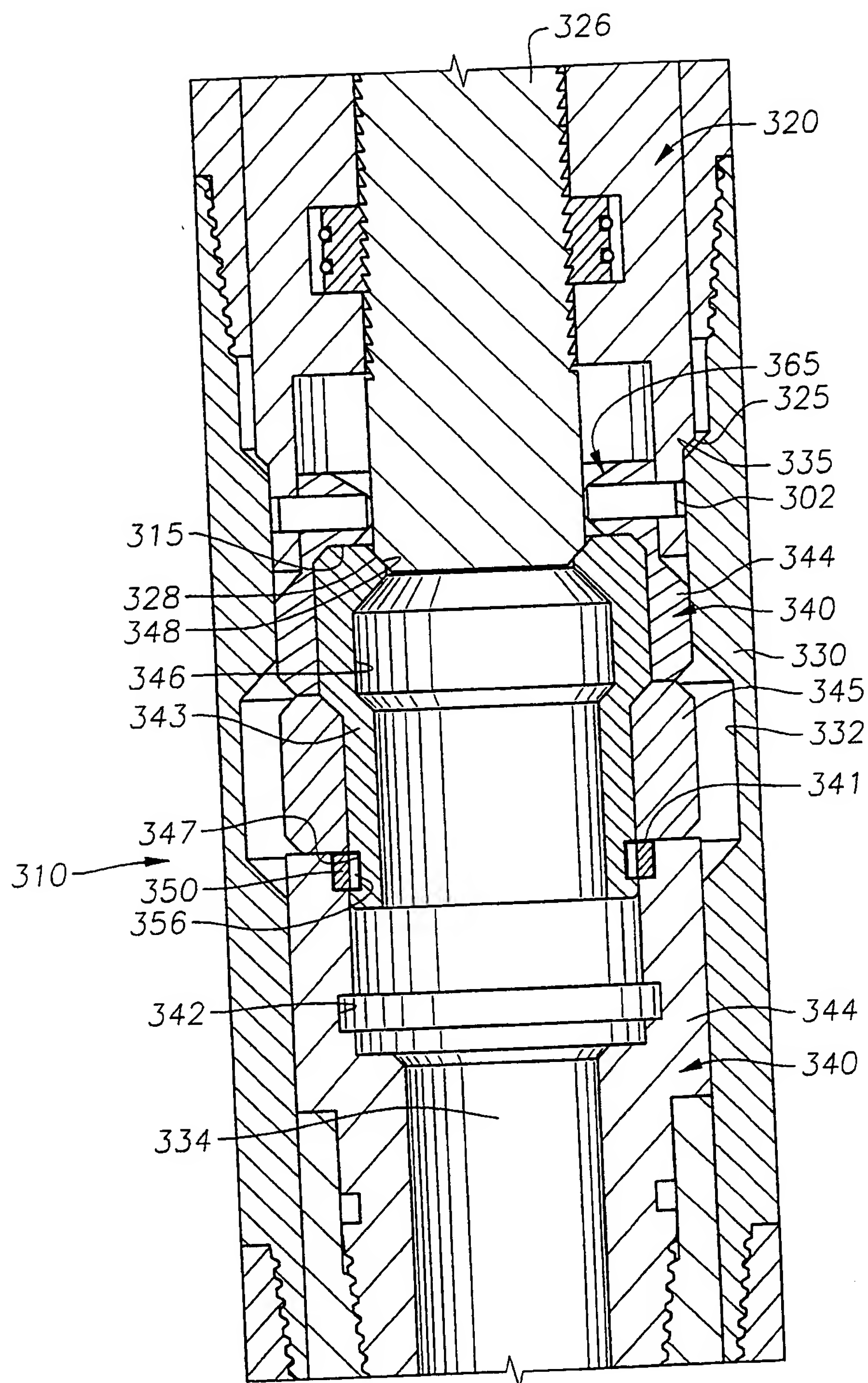


Fig. 6

7/7

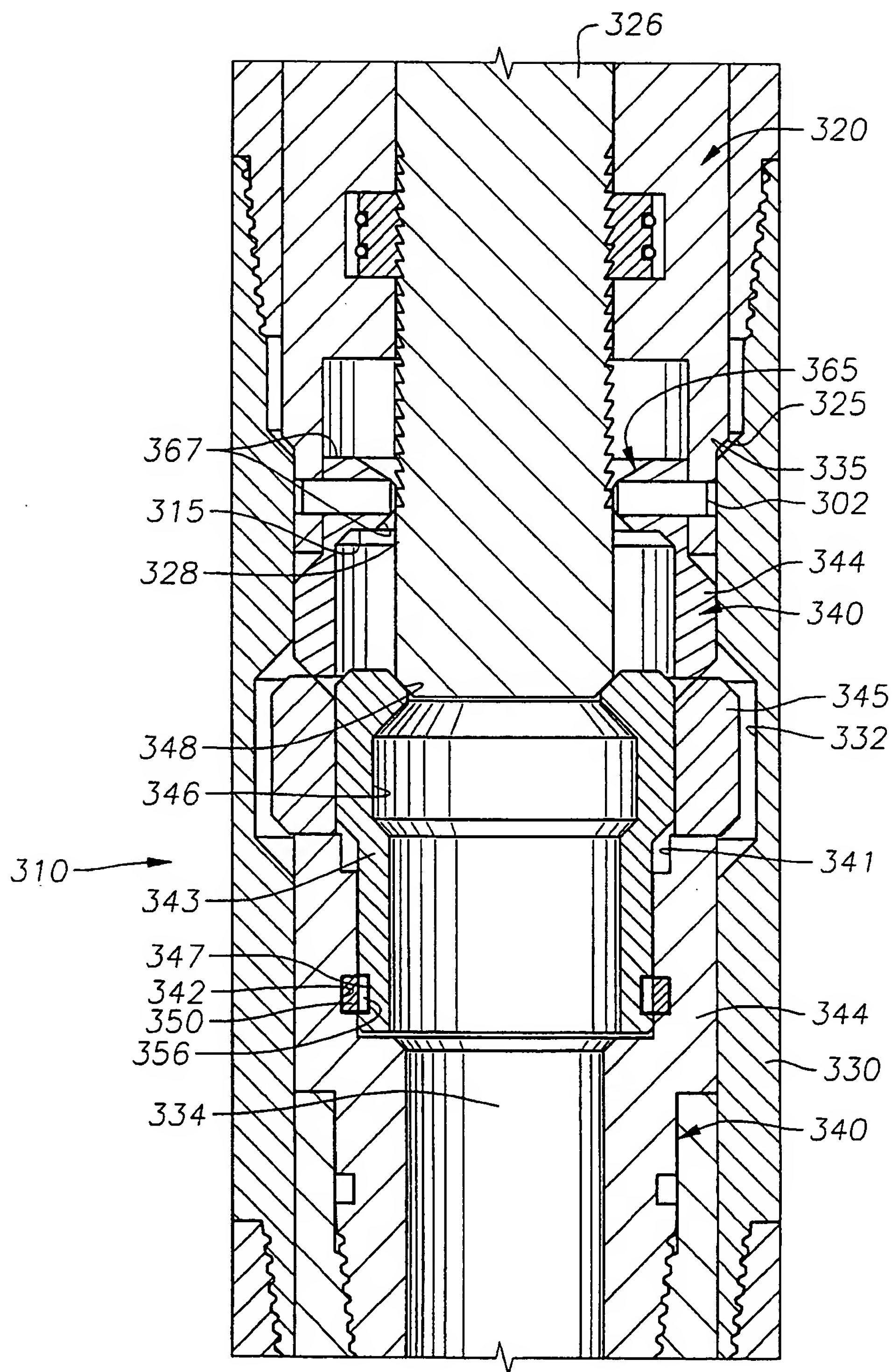


Fig. 7

## INTERNATIONAL SEARCH REPORT

International application No.  
PCT/US99/07852

## A. CLASSIFICATION OF SUBJECT MATTER

IPC(6) : E21B 37/06

US CL : 166/304

According to International Patent Classification (IPC) or to both national classification and IPC

## B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

U.S. : 166/242.4, 304, 310, 371, 902

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practicable, search terms used)

APS

search terms: fluorinated ethylene propylene or FEP, polyphenylene sulfide or PPS, coat###

## C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category*	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 5,105,879 A (ROSS) 21 April 1992 (21/04/92), see entire document, especially figure 5 and column 5.	1, 4, 5-31, 34-36, 40
X	US 4,671,833 A (BRADFORD et al.) 09 June 1987 (09/06/87), see entire document, especially column 4.	1,5-31, 34-36, 40
A	US 4,905,760 A (GRAY) 06 March 1990 (06/03/90), see entire document, especially columns 10 and 11.	32, 33, 38, 39
A	US 4,349,050 A (BERGSTROM et al.) 14 September 1982 (14/09/82), see entire document, especially column 3.	32, 33, 38, 39

☐ Further documents are listed in the continuation of Box C.☐ See patent family annex.

\* Special categories of cited documents:

\*A\* document defining the general state of the art which is not considered to be of particular relevance

\*E\* earlier document published on or after the international filing date

\*L\* document which may throw doubts on priority claim(s) or which is cited to establish the publication date of another citation or other special reason (as specified)

\*Q\* document referring to an oral disclosure, use, exhibition or other means

\*P\* document published prior to the international filing date but later than the priority date claimed

\*T\*

later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

\*X\*

document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

\*Y\*

document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art

\*&amp;\*

document member of the same patent family

Date of the actual completion of the international search

21 MAY 1999

Date of mailing of the international search report

16 JUN 1999

Name and mailing address of the ISA/US  
Commissioner of Patents and Trademarks  
Box PCT  
Washington, D.C. 20231

Facsimile No. (703) 305-3230

Authorized officer

ZAKIYA WALKER

Telephone No. (703) 305-0302

# INTERNATIONAL SEARCH REPORT

International application No.  
PCT/US99/07852

## Box I Observations where certain claims were found unsearchable (Continuation of item 1 of first sheet)

This international report has not been established in respect of certain claims under Article 17(2)(a) for the following reasons:

1. ☐ Claims Nos.:  
because they relate to subject matter not required to be searched by this Authority, namely:
  
2. ☐ Claims Nos.:  
because they relate to parts of the international application that do not comply with the prescribed requirements to such an extent that no meaningful international search can be carried out, specifically:
  
3. ☐ Claims Nos.:  
because they are dependent claims and are not drafted in accordance with the second and third sentences of Rule 6.4(a).

## Box II Observations where unity of invention is lacking (Continuation of item 2 of first sheet)

This International Searching Authority found multiple inventions in this international application, as follows:

Please See Extra Sheet.

1. ☒ As all required additional search fees were timely paid by the applicant, this international search report covers all searchable claims.
2. ☐ As all searchable claims could be searched without effort justifying an additional fee, this Authority did not invite payment of any additional fee.
3. ☐ As only some of the required additional search fees were timely paid by the applicant, this international search report covers only those claims for which fees were paid, specifically claims Nos.:
  
4. ☐ No required additional search fees were timely paid by the applicant. Consequently, this international search report is restricted to the invention first mentioned in the claims; it is covered by claims Nos.:

Remark on Protest

☐  
☐

- The additional search fees were accompanied by the applicant's protest.  
No protest accompanied the payment of additional search fees.

# INTERNATIONAL SEARCH REPORT

International application No.  
PCT/US99/07852

## BOX II. OBSERVATIONS WHERE UNITY OF INVENTION WAS LACKING

This ISA found multiple inventions as follows:

This application contains the following inventions or groups of inventions which are not so linked as to form a single inventive concept under PCT Rule 13.1. In order for all inventions to be searched, the appropriate additional search fees must be paid.

Group I, claim(s) 1-31, 34-37, and 40-41, drawn to a downhole tool comprising metallic parts having fluorinated ethylene propylene coating and method of use.

Group II, claim(s) 32, 33, 38, and 39, drawn to a downhole tool comprising metallic parts having polyphenylene sulfide coating and method of use.

The inventions listed as Groups I and II do not relate to a single inventive concept under PCT Rule 13.1 because, under PCT Rule 13.2, they lack the same or corresponding special technical features for the following reasons: Two products and processes of use are claimed.